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On the Performance of Noncontinuous Tight Gas Sands

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ABSTRACT

This paper discusses the development and application of a stochastic three-dimensional reservoir model for gas-water flow. The model treats the occurence of natural fractures and shales in the reservoir as random, and as such the discontinuities may be arbitrarily distributed among the reservoir grid blocks. A simple shale management scheme that does not require the formulation of a sand-shale permeability relationship is used. However, the developed model requires the estimation of effective flow properties for the fractured reservoir nodes. By this, we attempt to simulate the effective permeability measured by the slope of a fractured reservoir build-up curve. The model may be used to compute the reservoir performance of a fractured, lenticular sand gas reservoir as well as that of a conventional blanket sand. Results of demonstration problems based on published data on Paludal zones 3 and 4 of the Mesaverde formation in western Colorado suggest that the effects of sand lenticularity may not be as marked as have previously been calculated by modifying sand thickness by sand lense factor.

INTRODUCTION

The U. S. Geological Survey estimates Piceance Basin gas in place at 420 tcf, including 68 tcf potentially recoverable.[1] In order to develop these microdarcy fields to their economic production capacities, unconventional methods of production are required.

References and illustrations at end of paper.

The effort to develop such efficient production techniques is the principal objective of the U. S. Department of Energy's Multiwell Experiment (MWX)[2] located in the Rulison Field in the Piceance Basin of northwestern Colorado. The MWX field project is aimed at characterizing the lenticular, tight gas sands that are present in this region. The reservoir and stimulation information acquired from this field research was used in the hydraulic stimulation of the Paludal zones 3 and 4 of the Mesaverde formation. As the preliminary results[3] suggest, an optimum performance was not realized from the stimulation program. This is an indication of the difficulties encountered in developing noncontinuous, tight gas sands.

In situations such as the MWX problem, or in cases where conventional well methods are unreliable or impractical, computer-based simulators may be used to access the influence of each pertinent reservoir parameter on gas production. The effects on reservoir performance of such discontinuties as shales, natural fractures and faults are especially suitable for study by the use of numerical reservoir simulators. Such simulators would devise approximate, yet realistic, methods for generating idealized reservoir representations for subsequent evaluation of proposed field development schemes.[4]

There are simulation tools for noncontinuous gas reservoirs in existence.[4-9] The few papers cited represent only a partial list of the publications in this area. One of the major problems of modeling noncontinuous tight gas sands stems from the fact that the sands exhibit many internal permeability variations.[10] Property correlations developed for a particular sand lense may not be appropriate for other distributed lenses. Because of such problems, most developers of noncontinuous reservoir systems take the stochastic approach.

In this study, the same basic approach is adopted in the development of a 3-D water-gas flow model in which the presence of sand lenses and natural fractures are assumed random. This assumption is not unrealistic based on the report published by Lorenz and Finley.[11] Using the model described below, the performance of a fracture, lenticular gas reservoir was simulated. The results indicate that the effects of sand lenticularity may have been over estimated[7] in an earlier model by Evans and Ubani.[7]

THE MODEL

The model accounts for the effects of natural fractures and sand discontinuities on reservoir performance. Figure 1 represents an idealized sand-shale block with known sand-lense factor. Sand-lense factor in this context is defined as the fraction of sand volume in a given reservoir. A block may contain natural fractures whose concentration, orientation, average width and the pertinent flow properties are assumed known. The following simplifying assumptions are made in the development of the model.

MODEL ASSUMPTIONS

1. The fracture planes coincide with any two of the three principal permeability axes which are in turn arbitrarily oriented in the three cartesian axes.

2. All matrix blocks in the same cell block have the same bulk size.
3. All fractures are vertical and fully penetrate the vertical extent of the cell block.

4. A cell block represents either a sand node or a shale node.

The above assumptions were made in previous models of lenticular tight gas sands[7] to facilitate the calculations of the effective or cell block properties which are used in the solutions of the governing flow equations. All assumptions may be relaxed with appropriate modifications to the procedure for calculating effective, permeability and volume average porosity.

EFFECTIVE AND AVERAGE PROPERTIES

In calculating the effective or average flow properties, the relationships developed in our earlier work are used.[8] For the purpose of completeness the effective values are given by:

$$\bar{k}_{xx} = k_{xx}\left(1 - \frac{w_f}{\Delta y}\right) + k_{fx}\frac{w_f}{\Delta y} + k_{xx}\frac{w_f^2}{\Delta x.\Delta y} \quad ...(1)$$

$$\bar{k}_{yy} = k_{yy}\left(1 - \frac{w_f}{\Delta x}\right) + k_{fy}\frac{w_f}{\Delta x} + k_{yy}\frac{w_f^2}{\Delta y.\Delta x} \quad ...(2)$$

$$\bar{k}_{zz} = k_{zz}\left(1 - w_f\frac{\Delta x + \Delta y}{\Delta x.\Delta y}\right) + k_{fz}\, w_f\left(\frac{\Delta x + \Delta y}{\Delta x.\Delta y}\right) \quad ...(3)$$

$$\bar{\phi} = \phi_f\,\Delta V_f + \delta_m \Delta V_m \quad ...(4)$$

All assumptions that are made in the derivations of the above relationships are discussed in the report. Observe how the effective permeability expressions reduce to the corresponding matrix permeability for unfractured nodes. The fracture medium has attached porosity due to mineralization and/or silt deposition in the cracks. By seeking effective properties the rather complex flow problem is reduced to a manageable level. Also, it appears that randomly placed fractures is a more realistic approximation than regularly placed fractures.[12]

Sand Lenticularity

A basic assumption in this treatment of sand lenticularity is that the sand-shale volume ratio is known. Since the sand lenses are assumed stochastic, the sand and shale nodes may be randomly placed in a simulator grid system. A node is either a shale node or a sand node. The random node generation is terminated when the total generated sand-shale volume ratio matches the apriori known value. In other words, the fraction of the total grid blocks that is simulated as sand nodes corresponds to the sand lense factor.
In one of the earlier published reports on noncontinuous sand modeling,
Gidley et al[13] used Knutson's[9] work as a guide for manipulating a conventional reservoir simulator to match production performances of wells completed in low-permeability gas formations stimulated by massive hydraulic fracturing. Simulation results matched well production histories when the sand thickness available in the wellbore of the fractured well was reduced by the sand lense factor of 25%.

A similar approach of linearly adjusting the productivity index of a blanket sand to obtain the performance of lenticular sand performance was used in reference 7. This technique is equivalent to forcing the system to behave in a predetermined fashion. For tight gas sands, an over prediction of the effects of sand discontinuity on reservoir performance may result. In this study, no bias was introduced in the model so that the true effect of sand lenticularity on reservoir performance could be observed.

The flow equations that are presented below govern the transport of fluids in our proposed reservoir model.

Development of Model Governing Equations

The basic equations that are combined to develop the general gas-water flow equations in porous media are as follows:

1. Continuity Equation

$$\nabla \cdot (\rho_j \vec{v}_j) - \rho_{jsc}\, q_{jsc} =$$

$$\frac{\partial}{\partial t}(\phi\, \rho_j S_j) \qquad \ldots (5)$$

j = gas, water

2. Equation of Motion

$$\vec{v}_j = k_{rj}[K]\left(\nabla P_j - \rho_j \frac{g}{g_c} \nabla D\right) \ldots (6)$$

where

$$[K] = \begin{bmatrix} k_{xx} & 0 & 0 \\ 0 & k_{yy} & 0 \\ 0 & 0 & k_{zz} \end{bmatrix} \qquad \ldots (7)$$

3. Porosity Equation

$$\frac{\partial \phi}{\partial t} = c\, \frac{\partial P}{\partial t}(1 - \phi) \qquad \ldots (8)$$

The necessary auxiliary equations include

4. Saturations

$$S_g + S_w = 1 \qquad \ldots (9)$$

5. Capillary Pressure

$$P_c = P_g - P_w \qquad \ldots (10)$$

Equations (5) - (10) may be combined to give the following flow equations:

Water equation

$$\nabla \cdot \left[[K] \frac{k_{rw}}{\mu_w B_w} \left(\nabla P_w - \rho_w \frac{g}{g_c} \nabla D\right)\right] + q_w$$

$$= \left\{ \phi \left[S_w \frac{\partial (1/B_w)}{\partial P_w} - \frac{1}{B_w} \frac{\partial S_w}{\partial P_c}\right] + \right.$$

$$\left. \frac{S_w}{B_w} c\,(1 - \phi) \right\} \frac{\partial P_w}{\partial t}$$

$$+ \frac{\phi}{B_w} \frac{\partial S_w}{\partial P_c} \frac{\partial P_g}{\partial t} \qquad \ldots (11)$$

Gas Equation

$$\nabla \cdot \left[[K] \frac{k_{rg}}{\mu_g B_g} \left(\nabla P_g - \rho_g \frac{g}{g_c} \nabla D\right)\right] + q_g$$

$$= \phi \left(S_g \frac{\partial (1/B_g)}{\partial P_g} - \frac{1}{B_g} \frac{\partial S_w}{\partial P_c}\right) \frac{\partial P_g}{\partial t} +$$

$$\left(\frac{S_g}{B_g} c\,(1 - \phi) + \frac{\phi}{B_g} \frac{\partial S_w}{\partial P_c}\right) \frac{\partial P_w}{\partial t} \qquad \ldots (12)$$

Equations (11) and (12) govern the flow of gas and water in the proposed lenticular sand model, presented in this report. For a fractured node, the permeability is replaced by the effective permeability and the porosity by the weighted average porosity as computed in equations (1) - (4).

METHOD OF SOLUTION

The simultaneous solution (SS) approach is adopted in order to take advantage of the implicit treatment of transmissibilities.[14] In gas-water flow systems, the assumption of zero capillary pressure may not be realistic, especially in tight sands, and the formulation of such problems using implicit pressure, explicit saturation technique may not be appropriate. The resulting non-linear flow equations are approximated by finite differences where a variety of solution techniques exist. The system of linear equations are solved by iterative techniques -- line (block) successive overrelaxation (LSOR)[15] or point successive overrelaxation (PSOR).

MODEL APPLICATION

The following demonstration problems are chosen to illustrate two different boundary condition modes.

Case 1: Rate constrained well

The Multiwell Experiment Reservoir[2] (Paludal 3 & 4) presents a reasonable case to test the applicability of the model to lenticular, tight gas reservoirs. References 2 and 3 give useful information on the pre-fracture history of Paludal sands. Natural fracture characteristics are also given, although, only ranges of variables are provided. Based on those published characteristics, a set of simulation data was assembled for use in reproducing the pre-fracture pressure build up data for the reservoir.

Table 1 shows the major characteristics used in generating the result represented in figure 2. This model calculated a composite well block permeability of 38μd compared to the reported prefacture well test value of 36 μd.[16] A production period of 7 days was simulated with two step rates of 200 MCF/D and 250 MCF/D prior to shut in. With proper manupulation of the very sensitive variables (water saturation, fracture permeabilities, fracture width, and sand permeability), a better match than shown may be obtained. However, this match is adequate because the primary objective is to demonstrate the applicability of the developed model to a field situation.

For this example, a 10x10x2 grid system was used to simulate the reservoir size shown in Table 1. Time step size varied from 1 day to 5 days. Material balance error did not exceed 0.02%. However, the average number of iterations before convergence, using a tolerance of 0.1 psi was 20.

Case 2: Pressure Constrained Well

Except for the following changes, the same data set used in Case 1 was applied to investigate the effect of lenticularity of the production performance of a tight reservoir. A fixed bottom hole pressure of 1000 psia was used as the well boundary condition. Water saturation was assumed as 45%.

Figure 3 shows the predicted influence of sand discontinuity on cumulative gas recovery. Depending on the size and permeability of the sand lense in which the well is completed the reservoir will behave as a blanket sand initially. As the well block depletes, the effect of sand discontinuity may be observed. The time shown in figure 3 as the deviation point from the blanket sand curve may depend on the permeability of the sand. For our example reservoir, it takes about 200 days of flow before lenticularity starts to affect production. In this case, any performance projections made before this time may be too optimistic.

Figure 4 compares the results obtained using this model to that obtained by adjusting the well productivity index or reservoir thickness with the sand lense factor. The result shows that adjusting the sand thickness observed at the well bore by the sand lense factor as a method of accounting for sand discontinuity in a simulator may lead to extremely pessimistic predictions. We believe that the method tends to force the system to follow a pre-determined pattern. That is, production from a lenticular reservoir is assumed to be directly proportional to the sand lense factor.

These two examples illustrate how the proposed model may be applied to a discontinuous reservoir under gas-water production. The model is also amenable to a homogenous, non-fractured, reservoir under single phase gas flow.

An apparent problem with the model is that the effective properties for fractured nodes as given in equations (1) - (3) depend on the dimensions of the grid blocks. The choice of the number of grid blocks used to simulate a given reservoir may affect the results. Also, the interpretation of results obtained using this model should be only in the light of the assumptions listed in this paper.

CONCLUSIONS

The proposed approach to the handling of shale in lenticular reservoir does not require the formulation of a relationship which will involve variables or characteristics that are difficult to determine.

In low permeability sands, lenticularity may not affect reservoir performance early in the production history.

It may not be appropriate to decrease the sand thickness or the well productivity index by the sand lense factor when modeling a lenticular reservoir. This may yield pessimistic predictions.

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NOMENCLATURE

- B formation volume factor (BBL/STB or BBL/SCF)
- c compressibility (PSI^{-1})
- D depth measured downward (ft)
- g acceleration of gravity (ft/sec^2)
- g_c unit conversion factor (32.174 lbm - ft/lbf-sec^2)
- k absolute permeability (d or md)
- [K] permeability tensor (d or md)
- k_{rj} relative permeability of phase j
- P fluid pressure (psi)
- q flow rate (SCF/DAY/Volume or STB/DAY/Volume)
- s phase saturation
- t time (day)
- T temperature, °F
- v_j velocity of fluid phase j (ft/day)
- w natural fracture width (in)
- X,Y,Z rectangular coordinates
- μ fluid viscosity (cp)
- ρ fluid density (lbs/ft^3)
- ϕ porosity

Subscripts
- c capillary pressure
- f fracture
- g gas
- m rock matrix
- r relative value
- sc standard conditions
- w water

Symbols
- $\rightarrow$ vector
- ∇ nabla differential operator
- Δ delta or increment

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TABLE 1

RESERVOIR CHARACTERISTICS AND PRODUCTION DATA OF PALUDAL SANDS 3 & 4 USED IN MODEL

Reservoir length, width, thickness	2000,350,40 ft
Sand porosity	10.25%
Matrix permeability	3 md
Shale factor	30%
Fracture frequency	35%
Fracture permeability, k_{fmax}, k_{fmin}	5000,500 md
Maximum fracture width	1 mm
Fracture porosity	35-80%
Initial reservoir pressure	5350 psi
Initial gas saturation	70%
Gas production rate	200 - 250 MSCF/D
Gas specific gravity	0.65
Water specific gravity	1.04
Reservoir temperature	210 °F

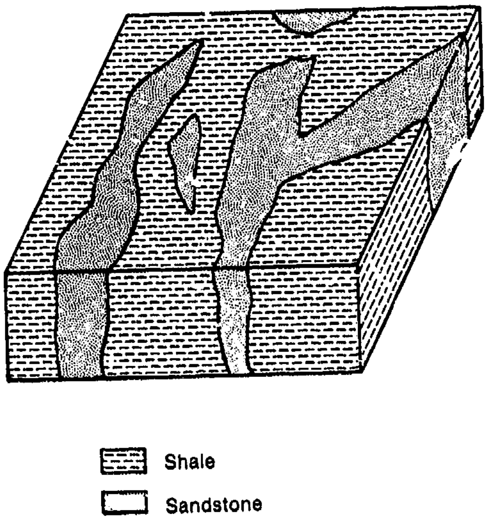

Fig. 1—Idealized lenticular reservoir block.

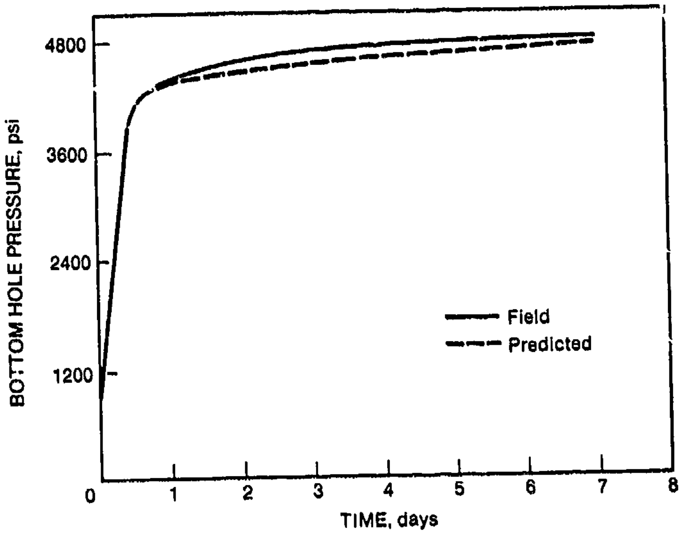

Fig. 2—Paludal Zones 3 and 4—predicted prefracture buildup pressure.

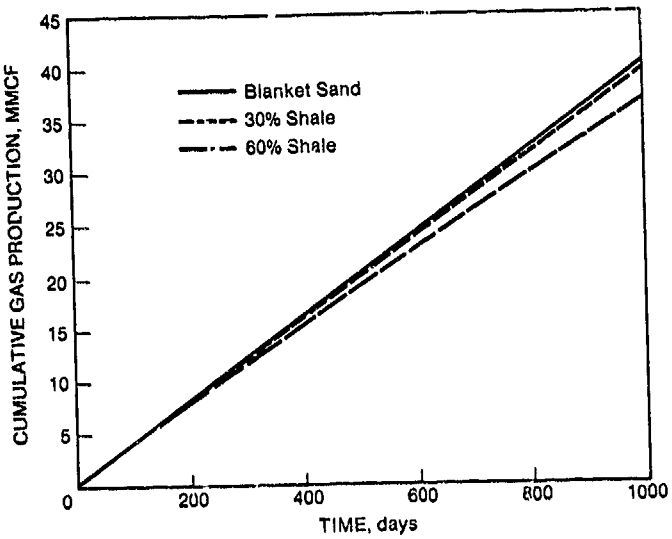

Fig. 3—Effect of sand and lenticularity on reservoir gas production.

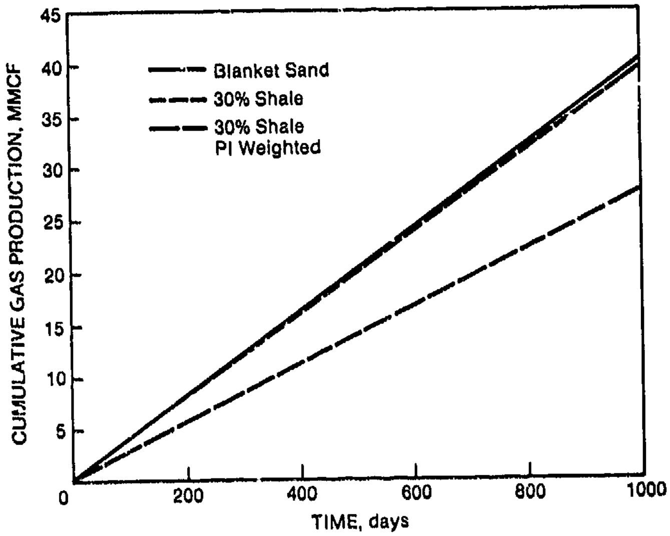

Fig. 4—Lenticular reservoir performance—effect of modeling technique on.

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